Under current law, oil and gas producers are allowed to recover depletable costs by deducting percentage depletion (I.R.C. sections 613 and 613A) or cost depletion (I.R.C. section 611); to recover intangible drilling costs through expensing (I.R.C. section 263c); and to recover depreciable costs through the Accelerated Cost Recovery System (I.R.C. section 168). Each of the provisions affect the amount of oil and gas drilling by altering the after-tax profitability of oil and gas investments.

Since 1975, federal tax law has differentiated between the integrated oil companies and the independents by exempting independents in whole or in part from oil industry tax increases. For tax purposes, an "independent" producer is classified as one engaged almost exclusively in the exploration and extraction phases of the oil business. An independent cannot refine more than 50,000 barrels in any single day during the year nor have annual retail sales in excess of $5 million. This excludes virtually all producers with significant downstream operations. Unless otherwise noted, this definition applies to all provisions concerning independent producers in the tax code.

A further distinction can be made between "small" independents and "large" independents. A small independent is one that fits the tax code definition of an independent producer, and whose production of oil and gas is less than 1,000 barrels per day.15/ A large independent produces over 1,000 barrels per day. The reason for this distinction is that production under 1,000 barrels per day (by independents) is eligible for percentage depletion, as well as lower rates of windfall profit tax; production over 1,000 barrels per day does not qualify for these provisions. Many of the top 400 oil and gas companies (see Table 1) are independents, but few (if any) produce less than 1,000 barrels per day.16/

DEPLETION

Firms in extractive industries, including oil and gas firms, are allowed a deduction to recover costs (as depletion) that reflect exhaustion of reserves by production. Depletion allowances are analogous to depreciation provisions for capital assets--both are intended to compensate the taxpayer for the decline in the value of assets over time.

15. Natural gas is put on an oil equivalent basis at the rate of 6,000 cubic feet of gas per barrel of oil.

16. Average production for companies 300th to 400th in size is 1,140 barrels per day per firm, exclusive of royalties and production payments.

Until 1975, all oil and gas producers were allowed to use either cost or percentage depletion, whichever was greater, for tax purposes. Percentage depletion allows a firm to deduct a fixed percentage of the gross income from the property, regardless of its actual initial cost or current basis. In contrast, cost depletion allows the firm to deduct a percentage of the historical cost equal to the percentage of estimated recoverable reserves produced in a given year. The cost basis of a property is its historical acquisition cost, which includes lease bonus payments, exploratory costs, and any capital expenditures that are not expensed (as are intangible drilling costs) or that are not subject to depreciation (as is lease equipment). Cost depletion is limited to the original cost basis of the property, while percentage depletion is computed without regard to the basis.

Prior to 1970, the percentage depletion rate was 27.5 percent. The rate was reduced to 22 percent in 1970 and was further restricted by the Tax Reduction Act of 1975 (P.L. 94-12). The 1975 Act limited the deduction to independent producers and royalty owners (excluding integrated companies) and allowed percentage depletion on only the first 2,000 barrels per day of production (phasing down to 1,000 barrels per day by 1980).17/ In addition, the act scheduled a reduction in the depletion rate from 22 to 20 percent in 1981, and phased the rate down to 15 percent in 1984 and for years thereafter. In 1985, about 20 percent of the value of oil and gas is estimated to be subject to percentage depletion--independent producers accounting for about 13 percent and royalty holders for 7 percent. The 1975 act also disallowed percentage depletion on proven properties that were sold after 1974, except in certain special circumstances. Table 2 presents the percentage depletion rates and relevant restrictions since 1926.

The Joint Committee on Taxation (JCT) estimates that the revenue loss from percentage depletion (measured relative to cost depletion) will be about $1.3 billion in 1986, and will total $6.9 billion over the 1986 to 1990 period.18/ For an independent

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17. Natural gas produced by independents is also allowed percentage depletion based on a conversion factor of 6,000 cubic feet per barrel of oil.

18. Joint Committe on Taxation, Estimates of Federal Tax Expenditures, 1986-1990 (April 12, 1985), Table 1.

TABLE 2. PERCENTAGE DEPLETION RATES ALLOWED FOR INDEPENDENT PRODUCERS

Year	Percentage of Gross Income (percent)	Quantity Limitation (bbl/day a/)
1926 - 1969 b/	27.5	None
1970 - 1974	22.0	None
1975	22.0	2,000
1976	22.0	1,800
1977	22.0	1,600
1978	22.0	1,400
1979	22.0	1,200
1980	22,0	1,000
1981	20.0	1,000
1982	18.0	1,000
1983	16.0	1,000
1984	15.0	1,000
1985+	15.0	1,000

SOURCE: Internal Revenue Code.

a. The quantity limitation imposes a limit on the amount of percentage depletion that can be claimed by each eligible company (or taxpayer). Alternatively, percentage depletion can be taken on a limited amount of natural gas production. The depletable gas quantity in cubic feet is the depletable oil quantity multiplied by 6,000.

b. Integrated companies were also allowed percentage depletion before 1975. An integrated company is defined as one that has more than $5 million in retail sales (on an annual basis) or refines more than 50,000 barrels on any day during the tax year.

producer, this tax subsidy is equivalent to an outlay subsidy of about $2 per barrel of oil.[19]

Percentage depletion may allow a company to recover more than the cost basis of the property over its useful life; cost depletion does not. This does not mean, however, that percentage depletion is preferable to cost depletion in every year. In the early years of a well's life, cost depletion allowances may exceed percentage depletion. Independent producers are allowed to deduct the greater of percentage or cost depletion (computed each year), and they will commonly deduct cost depletion in the early years of a well and switch over to percentage depletion in later years when the cost basis has declined sufficiently. During periods of rising oil prices, percentage depletion is highly preferable because the absolute size of the allowance increases with gross sales revenue, whereas cost depletion remains linked to the historical cost of the property.

In any cost recovery system, whether it is depreciation for equipment or depletion for oil and gas properties, a major consideration in determining the benefits of certain provisions is their timing over an investment's life. Because current tax deductions are worth more than those taken in the future, the sum of deductions over time can provide a misleading measure of the tax benefit provided by a given tax provision. The present value of deductions allowed under a certain provision accounts for differences in the timing of deductions over future years.

Percentage depletion can have a present value greater than the initial cost of a property. This may happen because percentage depletion is geared to actual production revenue, not to the original cost of the property. If a company pays a low bonus bid for a property, the present value of gross revenue can far exceed the original bonus amount. This is especially the case of high-risk properties where the probability of success is low (say 5 percent) and companies are unwilling to pay large amounts up front.

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19. This would be the subsidy required on the outlay side of the budget that would hold an independent producer harmless if percentage depletion were replaced with indexed cost depletion. It should be noted that this is a gross subsidy--the net subsidy would be less because it is assumed that the gross subsidy would be counted as part of income and subject to taxation. The actual subsidy received by any given producer is likely to vary widely depending on specific circumstances. The subsidy estimate made here is based on the "cost of capital" model discussed later in the text and in the Appendix.

As the above discussion points out, percentage depletion may be more generous than expensing of depletable costs (writing off the full cost in the first year).20/ If the Congress wanted to allow the equivalent of expensing, it could allow all full-lease acquisition costs as a deduction in the first year. Because gross income varies widely by property (and age of well), no single percentage depletion rate will yield the same result as expensing for all properties. Therefore, if the policy goal is to provide expensing, it would be easier and more accurate to allow firms to write off all of their oil and gas investments in the first year rather than to allow percentage depletion. This approach, however, could cause problems for taxpayers unable to use such a large deduction in the first year of a property's life.21/

For properties that are not productive, current law allows companies to write off depletable costs when properties are abandoned. (By definition, these properties are not eligible for any form of depletion.) For example, if a company pays a lease bonus of $10,000 for a property that proves to be worthless two years from now, it can deduct the $10,000 at that time. Similarly, if a company has not recovered the full amount of its depletable costs by the time it abandons a productive property, it may deduct those costs (less accumulated depletion) at that time.

50 Percent Taxable Income Limitation. Present law limits the deduction for percentage depletion to 50 percent of the taxable income from a property. Taxable income is defined as gross income less operating expenses, overhead, selling expenses, depreciation, and intangible drilling costs that are expensed. This limitation severely limits the production incentive offered by percentage depletion because it drastically reduces (and may eliminate) the deduction for those properties that are near their economic limit. (The economic limit is reached when the gross revenue from production equals current operating costs. As long as revenue exceeds operating costs, production will be maintained. At the point that operating costs exceed revenue, the property will be abandoned as uneconomic.)

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20. Expensing provides a good comparison because it implies a zero effective marginal tax rate on the asset. Under current law, intangible drilling costs are primarily expensed; the present value of depreciation deductions and the investment tax credit on three- and five-year ACRS property is also about equivalent to expensing. Other building and structure investments are accorded less generous capital recovery than expensing, however.

21. Firms could use any excess deductions in future years by carrying them forward.

For example, suppose a property generates $100,000 in gross revenue, and has net taxable income of $10,000. The net taxable income limitation reduces the otherwise allowable percentage depletion deduction from $15,000 to $5,000 (50 percent of $10,000). As taxable income goes to zero, so does the depletion deduction. Because of the net income limitation, percentage depletion may have virtually no effect on the incentive to keep stripper wells in production. Therefore, repealing the depletion allowance is unlikely to have any effect on shortening the life (or reducing production) from existing stripper (or other marginal) wells.

INTANGIBLE DRILLING COSTS

Until the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA--P.L. 97-248), both independent and integrated oil producers were allowed to deduct their expenditures for intangible drilling costs (IDCs) when they were incurred. These are capital expenditures with no salvage value, such as amounts paid for fuel, labor, materials, and supplies used in the preparation and drilling of oil or gas wells. They exclude expenditures for lease equipment, such as storage tanks or pumping machinery, which are treated as five-year recovery property under ACRS. Although lease equipment is eligible for the investment tax credit, intangible drilling costs (IDCs) that are expensed do not qualify for the credit. Since the combination of accelerated depreciation and the investment tax credit is about equivalent to expensing at a 10 percent discount rate, lease equipment and expensed IDCs currently receive similar effective tax treatment.

In TEFRA, the Congress reduced (to 85 percent) the percentage of IDCs that integrated oil corporations could expense; the Deficit Reduction Act of 1984 (DEFRA--P.L. 98-369) reduced this to 80 percent. The remaining 20 percent of an integrated firm's IDCs are amortized on a straight-line basis over 36 months. Independent companies may still deduct 100 percent of their IDCs. In present value terms, this amortization requirement has reduced the present value of the deduction for IDCs from 100 percent of total outlays to about 97 percent (using a discount rate of 10 percent). This limitation on expensing only applies to producing wells--costs associated with dry holes continue to receive full expensing treatment.

The JCT estimates that the revenue loss from allowing companies to expense IDCs will be $2.3 billion in 1986, and $13.8 billion over the 1986 to 1990 period. (This is measured

relative to unindexed cost depletion.) The outlay equivalent subsidy to this tax provision is about $4.75 per barrel.22/

Recapture. In the event that an oil and gas property is sold, the difference between the sales price and current basis is subject to capital gains taxation.23/ Under current law, long-term capital gains for corporations are subject to a top rate of 28 percent for corporations and a top rate of 20 percent for individuals. To the extent that a producer has elected to expense IDCs incurred after 1975, these amounts must be treated as ordinary income upon the sale of a property.24/ The amount included in ordinary income is reduced by the amount of deductions that would have been allowed under cost depletion had the producer decided to capitalize its IDCs instead of expensing them. This adjusted amount cannot exceed the total gain recognized upon the sale.

DEPRECIATION

Capital assets used in oil and gas exploration and production, such as pumps, holding tanks, collecting pipeline, or construction equipment, that have a salvageable value, are depreciated under the Accelerated Cost Recovery System (ACRS). Most depreciable assets employed in the oil and gas industry may be written off over five years.25/ The present value of depreciation deductions

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22. This is the per barrel subsidy on the outlay side of the budget that would hold producers harmless if the expensing provision were replaced by indexed cost depletion.

23. The current tax basis is the historical cost of the property (including depletable, depreciable and intangible drilling expenditures), less any deductions for depletion, depreciation, or intangible drilling costs.

24. The term "recapture" is used to reflect the fact that these costs were deducted against ordinary income and are taxed upon sale as ordinary income, instead of at lower capital gains rates. Since drilling costs produce an asset that has a value long after the deduction has been taken, this recapture provision is intended to prevent taxpayers from taking deductions against ordinary income and then realizing a gain from the sale of an asset that is taxed at a much lower rate.

25. Under 5-year ACRS, firms may deduct 15 percent of the cost of the asset in the first year, 22 percent in the second year, and 21 percent in each of the three remaining years.

under ACRS (at a 10 percent discount rate) is 84 percent of an asset's cost. Five-year ACRS property is also eligible for a 10 percent investment tax credit. The credit is accompanied by a requirement that firms reduce the depreciable basis of the affected assets by 50 percent of the credit (that is, 5 percent).26/

By themselves, depreciation deductions under ACRS are not as generous as expensing, but in combination with the investment tax credit (for which intangible drilling costs and depletable assets are not eligible), the present value of tax savings exceeds the present value of savings under full expensing. The present value of depreciation and the 10 percent investment tax credit is 102 percent of the asset's cost.27/ This implies that ACRS property is treated more favorably than expensing (at a 10 percent discount rate), and more favorably than expensed intangible drilling costs. At higher discount rates (perhaps indicating higher inflation), the present value of ACRS (and the credit) declines and is worth less than expensing.

THE WINDFALL PROFIT TAX

The Crude Oil Windfall Profit Tax Act of 1980 established a federal excise tax on oil production based on an estimate of the windfall profit received by producers as a result of oil price decontrol. The tax does not apply to natural gas production. The act established three categories of oil and set different tax rates for each class. The three oil "tiers" are defined as follows:

Tier One. All oil except that oil classified as Tier Two or Tier Three.

Tier Two. Stripper oil (that is, oil produced from wells with less than 10 barrels per day of production) and oil produced from the Naval Petroleum Reserve.

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26. Effectively, this reduces the present value of ACRS deductions by 5 percent to 80 percent. Firms also have the option of reducing their credit by two percentage points, but this is generally not preferable.

27. Again, discounted at 10 percent. The credit is converted into its "deduction equivalent" at the top corporate tax rate of 46 percent. At this rate, the credit is equal to a deduction of 22 percent.

Tier Three. Newly discovered oil (production from properties developed after 1978), heavy oil, and incremental tertiary oil.

The standard tax rates specified by the law are 70 percent (of the windfall profit)28/ on tier one oil, 50 percent on tier two oil, and 30 percent on tier three oil.29/ For oil in either tier one or tier two, the act specified reduced rates for independent oil producers on their first 1,000 barrels of production per day.30/ The reduced rate on tier one oil is 50 percent and on tier two 30 percent; there is no reduced rate on tier three oil. Table 3 sets out the tax rates and production shares for 1983 in each category of oil.

Tier One. In 1983, tier one oil was approximately 66 percent of taxable domestic production.31/ Six percent of tier one oil was subject to the lower 50 percent rate for independents. Excluding Alaskan oil, this advantage was equivalent to about $1.50 per barrel of production. This benefit, however, will decline as long as oil prices decline or remain steady (or increase less than the rate of inflation). Because the windfall profit declines if oil prices rise less than the GNP deflator, the tax differential is smaller when oil prices are lower.

Stripper Exemption. Stripper oil (about 14 to 15 percent of domestic production) was subject to reduced rates (under tier two) for independent producers under the 1980 act. This advantage was

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28. The windfall profit is defined as the difference between the market wellhead price and the 1979 base price. For example, the tax on tier one oil equals 70 percent of the market price less the base price; that is, tax = 0.7 percent (market price - base price). The base price is indexed to reflect changes in the GNP deflator each year.

29. The tax rate on newly discovered oil was reduced by the Economic Recovery Tax Act of 1981 to 15 percent over a six-year period. This transition was slowed down by DEFRA. The current rate is 22.5 percent and will be 15 percent starting in 1989.

30. As defined by the Windfall Profits Tax Act of 1980, an independent's status is determined on a quarterly basis instead of on an annual basis. Thus, in any quarter an independent cannot refine more than 50,000 barrels on any day nor have retail sales in excess of $1.25 million.

31. In 1983, total oil production was about 8.7 million barrels per day. Of this amount, about 85 percent (7.4 million barrels per day) was subject to tax.

TABLE 3. SHARES OF TAXABLE PRODUCTION AND WINDFALL PROFIT TAX LIABILITY BY OIL TIER (1983) a/

Oil Tier	Percent of Taxable Oil Production	Percent of Windfall Profits Tax Liability
Tier One	65.6	84.6
Taxed at 70 percent	61.6	79.1
Taxed at 50 percent	4.0	5.5
Tier Two	8.6	8.9
Taxed at 60 percent	8.0	8.5
Taxed at 30 percent b/	0.6	0.4
Tier Three (Taxed at 30 percent)	25.8	6.6
Newly discovered c/	16.8	4.7
Incremental tertiary	4.0	1.4
Heavy oil	5.0	4.6
Total	100.0	100.0

SOURCE: U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 2 (Fall 1984), p. 67.

a. Taxable production excludes production that is exempt, such as state and local government interests, Indian oil, or charitable interests.

b. Production in this class is basically stripper production, which has been made exempt from tax as of January 1, 1983.

c. The tax rate on newly discovered is now 22.5 percent and will decline to 20 percent in 1988 and to 15 percent in 1989 and thereafter.

increased by a provision in the Economic Recovery Tax Act of 1981 (ERTA--P.L. 97-34) that exempted all stripper production by independent companies. (About 45 percent to 50 percent of otherwise taxable stripper production is eligible for this exemption.) In the third quarter of 1984, the average tax per barrel of tier two oil (produced by an integrated company) was about \$4.20.32/ Since then, the decline in oil prices has eroded the tax to an estimated \$2.00 per barrel.

The exemption for stripper oil does not count against a firm's 1,000 barrel limit on oil eligible for reduced rates in either tier one or tier two. (Independents could have some tier two production resulting from the Naval Petroleum Reserve.) A firm could, for example, exempt 700 barrels per day of stripper oil and still receive favorable tax treatment on 1,000 barrels per day of tier one and tier two oil.

The exemption of stripper oil was justified in order to prevent "premature abandonment of such properties as the costs of production rise relative to the income available from the property."33/ This exemption has the effect of extending the economic life (and increasing the ultimate total production) of oil wells that are marginally profitable. Restriction of this exemption to independent producers seems inconsistent with the stated intent of the law, however. In 1982, about 33 percent of the output from stripper leases was produced by the top 32 companies (on a net company basis). This indicates that stripper oil production is not solely a province of the independent firm. The objective of increasing oil production does not by itself support a policy of providing an incentive for independents to extend the life of wells, while not providing the same incentive for integrated firms.

Tier Three Oil. Oil production from properties that were discovered after 1978, heavy oil, and incremental tertiary production are taxed as tier three oil. This tier is taxed at a statutory rate of 30 percent, although a reduced rate of 22.5 percent (declining to 15 percent in 1989) is provided for new oil. The effective tax rate (dollars per barrel) on this tier is now very low because the estimated windfall profit on each barrel has declined substantially in recent years. This is because market oil prices have declined since 1981, and because the formula for computing the adjusted base price increases at a real rate of 2 percent per year above inflation. (This extra 2

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32. U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 5, no. 1 (Summer 1985), p. 88.

33. Joint Committee on Taxation, General Explanation of the Economic Recovery Tax Act of 1981, p. 321.

percent only applies to tier three oil.) In fact, by the end of 1985, most tier three oil production should be effectively exempt from the windfall profit tax. Since much of new domestic production will be regarded as tier three oil, the windfall tax now imposes very little (if any) disincentive to invest in new sources of oil production. The tax will, however, continue to impose a burden on new production from old properties and on stripper production owned by integrated companies. Under current law, the windfall profit tax is scheduled to expire by the end of 1994.